BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.	Rulemaking 13-02-008 (Filed February 13, 2013)

REPLY COMMENTS OF SIERRA CLUB AND FOOD AND WATER WATCH TO THE JOINT COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, PACIFIC GAS AND ELECTRIC COMPANY, AND SOUTHWEST GAS CORPORATION REGARDING HYDROGEN-RELATED ADDITIONS OR REVISIONS TO THE STANDARD RENEWABLE GAS INTERCONNECTION TARIFF

Sara Gersen
Nina Robertson
Matt Vespa
Sasan Saadat
Email: sgersen@earthjustice.org
nrobertson@earthjustice.org
mvespa@earthjustice.org
ssaadat@earthjustice.org
Earthjustice
50 California Street, Suite 500
San Francisco, CA 94111
(415) 217-2000

Representing Sierra Club

Tyler Lobdell
Email: tlobdell@fwwatch.org
Food & Water Watch
1616 P St. NW, #300
Washington, DC 20036
(208) 209-3569

Representing Food & Water Watch

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Pursuant to the *Administrative Law Judge's Ruling Directing Joint Utilities and Other Parties to File Comments in this Proceeding* dated February 3, 2021, Sierra Club and Food & Water Watch respectfully submit these reply comments.

INTRODUCTION

To address the climate crisis and meet California's air quality and equity requirements, the Commission must take immediate steps to rapidly reduce greenhouse gas emissions ("GHGs") and other air pollution from the gas distribution network. To these ends, the Commission must aggressively pursue cost-effective investments in electrification that can leverage technologies that are available today to decarbonize the end-uses that currently rely on the gas system. Many years in the future, renewable hydrogen may offer an opportunity to incrementally reduce the carbon-intensity of pipeline gas, even if the existing gas system is a low-priority use for the limited supplies of renewable hydrogen. In this proceeding, the Commission can set the ground rules to ensure any injection of hydrogen does not perpetuate reliance on fossil gas or pose other unacceptable risks. Sierra Club and Food & Water Watch urge the Commission to adopt policies to ensure that hydrogen injection will not increase the carbon intensity of pipeline gas, create new safety and reliability risks, bloat the gas system with new costs, or increase health-harming emissions.

Two of the basic precautions the Commission should take against hydrogen inadvertently increasing greenhouse gas emissions are to refuse any requests to inject hydrogen that is not renewable into the gas system and define renewable hydrogen to include only electrolytic hydrogen whose production is powered by renewable electricity. Specifically, if the Commission determines that it would be safe to inject hydrogen into the gas pipeline network and decides to include renewable hydrogen in the Standard Renewable Gas Interconnection Tariff, the Commission should only allow injection of hydrogen that meets the following criteria:

1. The hydrogen is derived from electrolysis of water using Renewable Portfolio Standard ("RPS")-eligible renewable electricity satisfying Product Content Category 1, purchased pursuant to a contract that provides for the RPS-eligible renewable electricity to be delivered in the same hour that it is used for hydrogen production.
2. The hydrogen producer retires the Renewable Energy Credits for all the electricity used to produce the hydrogen.

Only hydrogen that meets these requirements has shown the potential to help decarbonize pipeline gas.

The Commission should reject the Joint Gas Utilities'[1] problematic proposed definition of renewable hydrogen, which includes carbon-intensive hydrogen derived from biomethane[2] and biomass. According to the Joint Gas Utilities, "renewable hydrogen" should mean hydrogen derived from one of the following:

> 1) Electrolysis of water using renewable electricity. In this context, renewable electricity refers to electricity produced from sources which are eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36.
> 2) Steam methane reforming (SMR), autothermal reforming (ATR), or methane pyrolysis of Renewable Gas (RG).
> 3) Thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW).[3]

There are several flaws with the Joint Gas Utilities' proposal to deem hydrogen "renewable" if it is produced from the steam methane reformation of any "renewable gas" or the thermochemical conversion of any biomass. First, this definition ignores the fossil fuels that power these energy-intensive production processes. Second, it assumes that any biogenic feedstocks are

[1] "Joint Gas Utilities" refers to Southern California Gas Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southwest Gas Corporation.
[2] These comments use the term biomethane to refer to mean methane from organic sources, which is also sometimes called renewable gas, renewable natural gas, or biogas.
[3] Joint Comments of Southern California Gas Company (U 904 G), San Diego Gas & Electric Company (U 902 G), Pacific Gas and Electric Company (U 39 G), and Southwest Gas Corporation (U 905 G) Regarding Hydrogen-Related Additions or Revisions to the Standard Renewable Gas Interconnection Tariff (Feb 22, 2021) at 3 ("Joint Gas Utilities Comments").

"renewable," even though the production and harvesting of biogenic feedstocks are often damaging to the climate. Third, Joint Gas Utilities' bid to convert biomethane into hydrogen for injection into the gas pipeline would make it more difficult to reduce the carbon intensity of the gas pipeline because the conversion process would use up the energy in biomethane, whose scarcity is already a barrier to decarbonizing pipeline gas. Finally, the Joint Gas Utilities' loose definition would leave the door open to hydrogen producers calling their hydrogen "renewable" when they purchase biomethane to offset the fossil fuels they actually use for hydrogen production.

The Commission does not have sufficient data to identify production pathways involving biomethane and biomass feedstocks that could meet any reasonable definition of renewable hydrogen. When the Commission began considering modifications to the SGIP Handbook that would have made "green" or "renewable" hydrogen eligible as a renewable fuel, even Pacific Gas & Electric Company recommended that the "Commission conduct a study to determine the feasibility, costs and benefits of adding green/renewable hydrogen as an eligible renewable fuel."[4] If the Commission adopts a definition of renewable hydrogen in this proceeding that includes such feedstocks, it is essential that the Commission's approach be cautious and fact-based because hydrogen from many biogenic production pathways would increase the carbon intensity of pipeline gas.

The Commission should also reject the hydrogen industry's even more misguided proposed definition of eligible hydrogen.[5] The hydrogen industry uses the term "green" hydrogen in apparent recognition that its so-called green hydrogen would include hydrogen from non-renewable energy and resources. The Commission should reject the proposal to use the industry's concept of "green" hydrogen because it includes production processes that emit climate and health-harming pollution greenhouse gas emissions, will increase pollution, and because it would deceive customers to label hydrogen produced from environmentally damaging feedstocks—such as cattle manure and logged forests—as "green."

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[4] Comments of Pacific Gas and Electric Company (U 39 E) on Assigned Commissioner's Ruling Seeking Party Comment on Renewable Generation Fuels and Technologies (Nov. 18, 2020) at 8, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M351/K406/351406679.PDF.

[5] *Id.* (describing similar proposals from the California Hydrogen Business Council and Green Hydrogen Coalition for the Commission to adopt a definition of "green" hydrogen that is more expansive than the Joint Gas Utilities' proposed definition of renewable hydrogen).

Finally, the Commission should adopt policy principles now to ensure that any future pipeline injection of hydrogen does not threaten safety and reliability, the ratepayers' interests in avoiding stranded assets, or public health. The Commission should address the following key issues and clarify the circumstances under which it would not be reasonable to allow the Joint Gas Utilities to inject hydrogen into the distribution system:

1. What level of hydrogen, if any, can be safely blended into pipeline gas. As the Joint Gas Utilities acknowledge, there is not sufficient information on how much hydrogen they could safely blend into pipeline gas.[6] <u>The Commission should clarify that it will not allow pipeline injection of hydrogen unless there is compelling evidence that doing so would not impede safety and reliability.</u>

2. Whether the safe injection of hydrogen would require investments to upgrade the gas pipeline network. <u>The Commission should articulate now that it will not allow any upgrades that will further perpetuate dependence on a pipeline system based on fossil gas. If upgrades are needed, the Commission should refuse ratepayer recovery of such investments to protect customers from paying for stranded gas system assets.</u>

3. Whether pipeline injection of hydrogen would increase health-harming emissions from gas-fired appliances, turbines, and vehicles before allowing utilities to blend renewable hydrogen into pipeline gas. <u>The Commission should affirm that it will not allow pipeline injection of hydrogen unless it first determines that hydrogen would not increase emissions from any equipment that burns gas.</u>

The Commission should commit to these precautions so that any future injection of renewable hydrogen does not cause serious harm.

DISCUSSION

I. If the Commission Adopts Standards for Injecting Hydrogen into Gas Pipelines, the Commission Should Only Allow the Injection of Electrolytic Hydrogen Produced with Renewable Energy.

The Commission's support for hydrogen injection must focus only on hydrogen that is suitable for a fully sustainable energy transition, which currently means it should be limited to hydrogen produced from electrolysis using renewable energy. Therefore, if the Commission

[6] Joint Gas Utilities Comments at 4-5.

adopts a definition for renewable hydrogen, it should define renewable hydrogen as hydrogen that meets the following criteria:

1. The hydrogen is derived from electrolysis of water using RPS-eligible renewable electricity satisfying Product Content Category 1, purchased pursuant to a contract that provides for the RPS-eligible renewable electricity to be delivered in the same hour that it is used for hydrogen production.
2. The hydrogen producer retires the Renewable Energy Credits for all the electricity used to produce the hydrogen.

At least for now, renewably powered electrolysis is the only production pathway for hydrogen that the Commission can confidently identify as producing hydrogen without causing greenhouse gas emissions or health-harming pollution to local air and water resources.[7]

Accordingly, renewable electrolytic hydrogen is the most widely accepted meaning of "green hydrogen"—a term that describes hydrogen's potential for achieving urgent climate goals. The International Renewable Energy Agency's "Green Hydrogen" guide for policy makers focuses only on renewables plus electrolysis, noting that this is the most established technology option.[8] The International Energy Agency likewise defines green hydrogen as hydrogen produced "using electricity generated from renewable energy sources,"[9] as does the European Bank for Reconstruction and Development ("made by using clean electricity from renewable energy technologies to electrolyse water"[10]), international energy companies like Iberdrola ("electrolysis from renewable sources")[11] and energy consultancies like Wood Mackenzie ("produced from water by renewables-powered electrolysis").[12] In explainer articles and popular educational materials that set out to answer "what is green hydrogen," the most

[7] The climate and local pollution impacts from the other production processes that the gas utilities propose to count as "renewable" are discussed below, in Discussion Section II.
[8] International Renewable Energy Agency, Green Hydrogen – A Guide to Policy Making (Dec. 2020) at 9 https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_hydrogen_policy_2020.pdf.
[9] IEA, Green Hydrogen for Use in Industrial Processes (Nov. 17, 2020) https://www.iea.org/articles/decarbonising-industry-with-green-hydrogen.
[10] Vanora Bennett, "Is Green Hydrogen the Sustainable Fuel of the Future?" (Jun. 22, 2020) https://www.ebrd.com/news/2020/is-green-hydrogen-the-sustainable-fuel-of-the-future-.html
[11] Iberdrola, "Green Hydrogen: An Alternative that Reduces Emissions and Cares for Our Planet" (Accessed Mar. 3, 2021) https://www.iberdrola.com/sustainability/green-hydrogen.
[12] WoodMackenzie, "The Rise of the Hydrogen Economy" (Accessed Mar. 3, 2021) https://www.woodmac.com/nslp/hydrogen-guide/.

common answer given is hydrogen produced from renewably-powered electrolysis.[13] Applying a broader definition to "renewable" or "green" hydrogen at the Commission could cause confusion because it would be a departure from international norms. The Commission should also avoid terms that could mislead customers about the environmental benefits of the hydrogen on offer, as discussed below in Section II.D.

Moreover, renewable electrolytic hydrogen should be a priority for policy support because it offers unique benefits as a decarbonization tool, which society will only be able to harness by deploying electrolyzers and renewable generation at sufficient scale to drive down costs. Specifically, leading analysts laud green hydrogen for its potential to harness surplus variable solar and wind energy.[14] Independent researchers find that one of the advantages of green hydrogen is that it "can be produced wherever there is water and electricity."[15] This is not a quality of technologies like biomass gasification, which requires the transportation of small, scattered supplies of biomass to large, centralized production facilities.[16] If the Commission seeks to stimulate a local renewable hydrogen industry that will develop technologies to decarbonize hard-to-abate sectors, it should promote investments in renewable electrolytic hydrogen.

To avoid double-counting environmental attributes, the Commission should only deem hydrogen "renewable" if the hydrogen producers retire all of the Renewable Energy Credits for the electricity they use in the production process. The California Energy Commission imposes this condition on hydrogen fuel cells if they seek eligibility under the Renewable Portfolio Standard.[17] Although the Joint Gas Utilities propose making hydrogen produced through

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[13] *See, e.g.,* Jason Deign, "So, What Exactly Is Green Hydrogen?" (June 29, 2020) https://www.greentechmedia.com/articles/read/green-hydrogen-explained *and* Renee Cho "Why We Need Green Hydrogen" *Columbia University - State of the Planet* (Jan. 7, 2021) https://blogs.ei.columbia.edu/2021/01/07/need-green-hydrogen/#:~:text=So%2C%20what%20is%20green%20hydrogen,its%20only%20byproduct%20is%20water.
[14] IRENA, Green Hydrogen – A Guide to Policy Making (Dec. 2020) at 9 https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_hydrogen_policy_2020.pdf.
[15] Renee Cho "Why We Need Green Hydrogen" *Columbia University - State of the Planet* (Jan. 7, 2021) https://blogs.ei.columbia.edu/2021/01/07/need-green-hydrogen/#:~:text=So%2C%20what%20is%20green%20hydrogen,its%20only%20byproduct%20is%20water.
[16] Iain Staffel *et al.*, The Role of Hydrogen and Fuel Cells in the Global Energy System, (Jan. 2019) at 477 https://pubs.rsc.org/en/content/articlepdf/2019/ee/c8ee01157eat.
[17] CEC, RPS Eligibility Guidebook (9th ed. revised) at 13 ("A facility converting hydrogen gas to electricity in a fuel cell may qualify for RPS certification if the hydrogen was derived from a non-fossil-based fuel or feedstock through a process powered using an eligible renewable energy resource. The electricity generated by a facility using this type of hydrogen gas is eligible for the RPS only if the electricity that was used to derive the hydrogen is not also counted toward an RPS compliance obligation or claimed for any other program as renewable generation.").

electrolysis of water using renewable electricity as an eligible type of renewable hydrogen, they fail to include this basic precaution.[18] Ensuring the integrity of the renewable electricity that powers hydrogen production is imperative because hydrogen produced through the electrolysis of grid-average electricity is even *more* carbon intensive than hydrogen produced through the reformation of fossil gas, as well as the fossil-derived methane that is already in the gas pipeline network.[19]

The requirements to use RPS-eligible electricity that satisfies Product Content Category 1 and contract for the delivery of that electricity in the same hour it is used for hydrogen production are also necessary to provide assurance that the hydrogen production actually avoids greenhouse gas emissions. In contrast, the hydrogen industry's proposal to include "pathways that use zero-carbon electricity sources that are not RPS-eligible" under an expanded concept of "green" hydrogen would invite resource shuffling that would negate the potential benefits of purchasing that electricity.[20] "Under resource shuffling, electricity contracts are rearranged so that production from low emission sources serving out-of-state load is directed to California, while production from higher emission sources is assigned to serve out-of-state load. This would result in apparent emission reductions due to changes in the composition of imports to California, although emissions in exporting regions are unchanged or even increase."[21] For instance, if the Commission accepted the hydrogen industry's proposal, hydrogen producers could rely on existing hydro generation in the Pacific Northwest to power their electrolysis, which might not contribute to overall emissions reductions because the entities that currently purchase power from the existing hydro resources could shift to purchasing fossil-fueled power.

The Commission should ensure that the Standard Renewable Gas Interconnection Tariff only includes hydrogen if it promotes California's climate goals, does not harm the environment,

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[18] Joint Gas Utility Comments at 3.
[19] According to the California Air Resource Board's Lookup Tables for the Low Carbon Fuel Standard, the carbon intensity of compressed hydrogen produced through steam methane reformation of North American fossil gas is 118 grams of CO2e/MJ, whereas compressed hydrogen produced in California from electrolysis using California grid average electricity has a carbon intensity of 164 grams of CO2e/MJ. CARB estimates that the carbon intensity of compressed natural gas from pipeline average North American fossil natural gas is 79 grams of CO2e/MJ. The Lookup Table with these carbon intensity values is available for download at https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.
[20] Joint Gas Utility Comments at 4.
[21] Lo Prete, Chiara, et al, "California's cap-and-trade program and emission leakage in the electricity sector: an empirical analysis" at 2 (Jan 3, 2019) (footnote omitted), https://sites.psu.edu/chiaraloprete/files/2018/11/Leakage_Lo-Prete_Tyagi_Hohl-wuaws1.pdf.

and compatible with the most widely accepted meaning of "renewable" or "green" hydrogen as described above. Therefore, any injection standards adopted at this time should be limited to renewable electrolytic hydrogen, as defined above.

II. The Commission Should Reject the Joint Gas Utilities' Proposed Definition for "Renewable" Hydrogen and the Hydrogen Industry's Proposed Definition for "Green" Hydrogen Because They Threaten to Create New Pollution Problems and Would Not Decarbonize the Gas Pipelines.

The Joint Gas Utilities' proposed definition of renewable hydrogen includes pollution-intensive processes for producing hydrogen from biomethane and biomass. The Joint Gas Utilities also support the hydrogen industry's definition of "green" hydrogen, which is even broader and more problematic. Both the Joint Gas Utilities' and hydrogen industry's preferred definitions would mislead customers regarding the environmental benefits of the hydrogen being marketed as renewable or green.

A. The Joint Gas Utilities' proposed definition of renewable hydrogen would include carbon-intensive production processes that burn fossil fuels.

The Joint Gas Utilities' unreasonably broad definition of "renewable" hydrogen includes energy-intensive industrial processes that rely on fossil fuels to convert biomethane and biomass into hydrogen. Specifically, the Joint Gas Utilities ask the Commission to consider hydrogen renewable if it comes from one of the following production pathways: "Steam methane reforming (SMR), autothermal reforming (ATR), or methane pyrolysis of Renewable Gas" or "Thermochemical conversion of biomass, including the organic portion of municipal solid waste."[22] Under current practice, each of these processes for converting biogenic feedstock depends on combustion of fossil fuels for power. Thus, the Joint Gas Utilities' inappropriate definition would deem hydrogen "renewable" if a facility used biomethane as a feedstock and fossil gas to power a steam methane reformation process to convert that biomethane into hydrogen. Yet hydrogen produced through fossil-powered steam methane reformation of biomethane is even *more* carbon intensive than the fossil gas that is already in the pipeline

[22] Joint Gas Utility Comments at 3.

system.[23] The Commission should avoid this absurd result and make clear that hydrogen is renewable only if it relies renewable energy to power its production process.[24]

B. The Commission should exclude hydrogen produced from biomethane and other "renewable" methane gas in the Standard Renewable Gas Interconnection Tariff.

1. The Commission should not allow the injection of hydrogen derived from biomethane into the gas pipeline network.

The Commission should not permit the injection of biomethane-derived hydrogen into the gas pipeline network because the process of converting methane gas to hydrogen via steam methane reformation has efficiency losses of about 28%.[25] As a result, hydrogen derived from biomethane only has about 72% of the energy that would be available for customers if it is simply injected into pipelines as biomethane. It would be irrational to waste a quarter of the energy in biomethane to create a more expensive and potentially dangerous pipeline gas.

The limited supply of biomethane is one of the key reasons that California will need to burn less gas to meet its climate goals. There is only enough potential biomethane supply to displace about 3% of California's fossil gas use.[26] Other sources of "renewable natural gas" are not yet commercially available.[27] In the most aggressive scenario laid out by the American Gas Foundation, after two decades of scaling up production of all sources, including gasified energy

[23] CARB estimates that the carbon intensity of compressed natural gas from pipeline average North American fossil natural gas is about 79 grams of CO2e/MJ, whereas the agency estimates the carbon intensity of compressed hydrogen produced through steam methane reformation of biomethane from landfills is about 99 grams of CO2e/MJ. The Lookup Table with these carbon intensity values is available for download at https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

[24] CARB estimates that to produce hydrogen from the steam methane reformation of biomethane producers will use .371 MMBtu of fossil gas to power the steam methane reformation process for every 1 MMBtu of biomethane feedstock. CARB, CA-GREET 3.0 Lookup Table Pathways Technical Support Document at 40, https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/lut-doc.pdf?_ga=2.15041334.1842319722.1614363121-1168559359.1580157486.

[25] CARB assumes steam methane reforming to have a production efficiency of 72%. Other literature reviews also assume an average efficiency of 72% for methane reforming. CARB, CA-GREET 3.0 Lookup Table Pathways Technical Support Document at 38, https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/ca-greet/lut-doc.pdf?_ga=2.15041334.1842319722.1614363121-1168559359.1580157486; Staffel *et al.*, The Role of Hydrogen and Fuel Cells in the Global Energy System, supra note 16, at 477.

[26] Jimmy O'Dea, "The Promises and Limits of Biomethane as a Transportation Fuel" (May 2017) Figure 1, at 2 https://www.ucsusa.org/sites/default/files/attach/2017/05/Promises-and-limits-of-Biomethane-factsheet.pdf.

[27] California Energy Commission, The Challenge of Retail Gas in California's Low-Carbon Future (April 2020) at 40, https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.

crops, only 14% of U.S. gas demand could be met by non-fossil gases.[28] Thus, even under the gas industry's optimistic projections for the availability of "renewable gas" there is no excess of zero-carbon methane that could justify using it inefficiently in the pipeline network.

Given the relative scarcity of biomethane, converting it to hydrogen is an imprudent and wasteful strategy for decarbonizing pipeline gas, and the Commission should therefore not include it in the definition of renewable hydrogen.

2. If the Commission nevertheless allows hydrogen derived from biomethane, it should prohibit the use of biomethane credits and other schemes for deeming fossil gas to be "renewable."

The Joint Gas Utilities do not define the "renewable gas" that could serve as feedstock in the production of renewable hydrogen, leaving open the possibility that they could use fossil gas as a feedstock and merely purchase credits for biomethane under the false pretense that such credits render the fossil gas renewable. Given this risk, if the Commission accepts the Joint Gas Utilities' proposal and allows injection of renewable hydrogen that is "derived from" biomethane (which it should not for the reasons described above), the Commission should ensure that the hydrogen is *actually derived from* the biomethane and not based on the purchase of a biomethane credit. The Commission can accomplish this by requiring the hydrogen producer to use the biomethane onsite at the facility that captures it or receive the biomethane via a dedicated pipeline.

Fallacious industry claims regarding biomethane have long threatened the success of California's climate programs. In 2012, the California Legislature was so alarmed by utilities claiming that certain purchases of biomethane allowed them to generate "renewable" energy at gas-fired facilities that it added Public Utilities Code Section 399.12.6, limiting the eligibility of biomethane for the Renewable Portfolio Standard.[29] As detailed in the legislative history for Assembly Bill ("AB") 2196 (2012), California utilities were not using the far-off biomethane

[28] The American Gas Foundation report's high-resource scenario projects a maximum of 4512.6 tBtu/y of non-fossil gases could be available. According to the Energy Information Administration, natural gas consumption in 2019 was 31,099,061 million cubic feet, or 32,249.726 tBtu (at 1,037 btu per cubic foot). 4512.6 is 14% of 32,249.726. AGF, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment (Dec. 2019), at 3 https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Executive-Summary-Final-12-18-2019-AS-1.pdf; U.S. EIA, Natural Gas Consumption by End Use, https://www.eia.gov/energyexplained/natural-gas/useof-natural-gas.php (Accessed Mar. 3, 2021).

[29] Assembly Bill ("AB") 2196 (2012).

they procured to generate energy, and these contracts did not diminish California's reliance on fossil fuels:

> The guidelines for pipeline landfill and digester gas do not require displacement of fossil fuel consumption, the reduction of air pollution, or other environmental benefits to California. Additionally the contracts being signed by some California retail sellers and POUs were with landfills from as far away as Pennsylvania, Ohio and Tennessee, locales which make it physically impossible to verify delivery of the fuel to California particularly because the flow of those pipelines passes through pipelines flowing in the opposite direction of California. The RPS also intends that the program achieve "additionality," that new development of renewables occurs, but in the case of many of the contracts, the biomethane had been flowing for quite some time so that there appears to be no new capture or incremental capture occurring. Additionally, the current guidebook lacks vigorous requirements to verify that the claimed quantity of biomethane was actually used by the designated power plant or that the necessary biomethane attributes were transferred to the power plant operator for purposes of the RPS and not double-counted for other purposes.[30]

Here, if the Commission accepts the Joint Gas Utilities' loose definition of renewable hydrogen, industry will likely make the same absurd claims about using common carrier pipelines to receive biomethane that the Legislature rebuffed in 2012.

Despite the Legislature's decision to narrow eligibility for biomethane under the Renewable Portfolio Standard, the California Air Resources Board has failed to implement a definition of "renewable hydrogen" that reflects AB 2196[31]—allowing the industry to rely on dubious practices to claim credit for renewable hydrogen. A 2016 report from the National Renewable Energy Laboratory found that industry primarily complied with mandates to purchase renewable hydrogen by producing hydrogen through steam methane reformation and coupling it with the purchase of biomethane credits.[32] The report explains that "[t]he cost to produce renewable hydrogen with an electrolyzer is greater than the cost to install an SMR unit and pay the additional fee for renewable biogas [biomethane] credits."[33] Even under the constraints of AB 2196, the hydrogen industry could avoid developing new renewable production technologies by exploiting provisions that treat some biomethane shipped via common carrier as renewable.

[30] Senate Floor Analysis for AB 2196 (Aug. 31, 2012).
[31] For one example of a California Air Resources Board process that failed to apply a definition of renewable hydrogen that is consistent with AB 2196, *see* Clean Mobility in Schools Pilot Project: Hydrogen Refueling Station Requirements, pages F-5 to F-6 (Aug. 23, 2019), https://ww3.arb.ca.gov/msprog/mailouts/msc1920/msc1920appf.pdf.
[32] National Renewable Energy Laboratory, California Power-to-Gas and Power-to-Hydrogen Near-Term Business Case Evaluation (Dec. 2016) at 59, https://www.nrel.gov/docs/fy17osti/67384.pdf.
[33] *Id.*

See Cal. Public Utilities Code § 399.12.6(b)(3)(C). Industry will not have an incentive to deploy technologies that produce renewable electrolytic hydrogen as long as it can continue business as usual and use credits to claim that its hydrogen is renewable.

C. The Commission lacks a record for identifying sources of biomethane or biomass that would provide climate benefits.

The Joint Gas Utilities' proposed definition of renewable hydrogen includes no limits on eligible "renewable gas" and biomass feedstocks, which is problematic because many biogenic feedstocks are not carbon-neutral. For instance, the Joint Gas Utilities' unreasonably broad definition would include hydrogen derived from crops that are grown for the specific purpose of becoming an energy source. Although biomass conversion is sometimes touted as an opportunity to harness materials that would otherwise go to waste, the economic reality is that the cost-effective and logistically manageable sources of biomass are not dispersed waste streams, but energy crops. Data on the climate impacts of the U.S. EPA's Renewable Fuel Standard shows why it is essential to exclude purpose-grown energy crops as a feedstock for renewable hydrogen. The Renewable Fuel Standard provides an incentive to increase biofuel production even though the EPA's *own* review showed the program had led to the conversion of up to 8 million acres of land—nullifying and overwhelming any climate benefit the program might have had.[34] If the Commission adopts a definition of renewable hydrogen before it understands the impacts of different feedstocks and pathways, it could inadvertently encourage projects that damage the climate. If the Commission sought to correct course and refine its definition of renewable hydrogen later, it would face an uphill battle against vested market actors.

Forest biomass is another example of a potential biomass feedstock that could contribute significant greenhouse gas emissions. Claims that forest biomass is a carbon-neutral source of energy generally rest on the unsupported assumption that the forests will regrow and capture enough carbon to make up for the emissions from logging the forests and converting its biomass into energy. Here, the Joint Gas Utilities' expansive definition of renewable hydrogen would include forest biomass regardless of whether landowners develop the land for other purposes or they allow the forests to sequester the lost carbon. Even when trees can regrow, it takes many

[34] Environmental Protection Agency, Biofuels and the Environment: The Second Triennial Report to Congress, at 37 (June 29, 2018), https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=IO&dirEntryId=341491.

decades or more than a century for forests to recapture the carbon that enters the atmosphere when forests are logged for energy.[35] One study concluded that using forest biomass for energy could permanently increase the amount of carbon dioxide in the atmosphere.[36] The Commission should not treat biomass-derived hydrogen as renewable without assurances that the specific biomass feedstock is not contributing carbon emissions.

Just like producing hydrogen from unrestricted sources of biomass, producing hydrogen from biomethane could harm the climate. Studies that model reduced emissions from biomethane-based hydrogen "usually do not include a full carbon balance. A cut-off approach is normally adopted, where the [biomethane] comes burden-free."[37] Although industry proponents sometimes call biomethane a "carbon negative" resource, such claims rest on subjective modeling choices such as whether to categorize the feedstock as waste and whether to include the burdens of anaerobic digestion.[38] It is unreasonable to assume that biomethane would be emitted but-for its conversion to hydrogen, particularly when considering methane from cattle manure. The agricultural industry and policy makers have several strategies they could use to ensure that dairies do not produce biomethane from manure in the first place.[39] Creating a market for biomethane encourages the dairy industry to forego these alternatives and consolidate operations into concentrated animal feeding operations ("CAFOs") or further expand existing

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[35] Searchinger, T.D. *et al*., Fixing a critical climate accounting error, 326 Science 527 (2009); Gunn, J., et al., Manomet Center for Conservation Sciences, Massachusetts Biomass Sustainability and Carbon Policy Study: Report to the Commonwealth of Massachusetts Department of Energy Resources (2010); Hudiburg, T.W. et al., Regional carbon dioxide implications of forest bioenergy production, 1 Nature Climate Change 419 (2011); Law, B.E. and M.E. Harmon, Forest sector carbon management, measurement and verification, and discussion of policy related to climate change, 2 Carbon Management 73 (2011); Campbell, J.L. et al., Can fuel-reduction treatments really increase forest carbon storage in the western US by reducing future fire emissions? 10 Frontiers in Ecology and Environment 83 (2012); Holtsmark, Bjart, The outcome is in the assumptions: Analyzing the effects on atmospheric CO2 levels of increased use of bioenergy from forest biomass, 5 GCB Bioenergy 467 (2012); Mitchell, S.R. et al., Carbon debt and carbon sequestration parity in forest bioenergy production, 4 Global Change Biology Bioenergy 818 (2012); Schulze, E.-D. et al., Large-scale bioenergy from additional harvest of forest biomass is neither sustainable nor greenhouse gas neutral, 4 Global Change Biology Bioenergy 611 (2012); Booth, Mary S., Not carbon neutral: Assessing the net emissions impact of residues burned for bioenergy, 13 Environmental Research Letters 035001 (2018); Sterman, John D. et al., Does replacing coal with wood lower CO2 emissions? Dynamic lifecycle analysis of wood bioenergy, 13 Environmental Research Letters 015007 (2018).

[36] Holtsmark, Bjart, The outcome is in the assumptions: Analyzing the effects on atmospheric CO2 levels of increased use of bioenergy from forest biomass, 5 GCB Bioenergy 467 (2012).

[37] Cristina Antonini et al., Hydrogen Production from Natural Gas and Biomethane with Carbon Capture and Storage - A Techno-Environmental Analysis (Mar. 11, 2020), https://pubs.rsc.org/en/content/articlelanding/2020/SE/D0SE00222D#!divAbstract.

[38] *Id.* (footnotes omitted).

[39] California Climate and Agriculture Network, Diversified Strategies for Reducing Methane Emissions from Dairy Operations (Oct. 2015), http://calclimateag.org/wp-content/uploads/2015/11/Diversified-Strategies-for-Methane-inDairies-Oct.-2015.pdf.

CAFOs because capital-intensive anaerobic digesters are only economic for CAFOs that produce and store large quantities of wet manure.[40] Even if the environmental sustainability of the feedstock gas *could* be assured, this process would still be limited by the challenge of eliminating any methane leakage during gas handling, the ability to fully capture the released CO2, and the finite availability of storage for captured CO2.[41] The theoretical potential for this pathway to be consistent with net-zero emissions is therefore unproven.

D. The hydrogen industry's preferred definition of "green" hydrogen would deceive customers, in violation of Federal Trade Commission guidance.

In California, "[i]t is unlawful for any person to make any untruthful, deceptive or misleading environmental marketing claim, whether explicit or implied."[42] As the Federal Trade Commission explains in its Green Guides, companies should avoid misleading customers by not claiming their products have a general environmental benefit.[43] Such claims "may convey that the item or service has no negative environmental impact" and "it is highly unlikely that marketers can substantiate all reasonable interpretations of these claims."[44] Marketing hydrogen as "green" would be a textbook example of claiming a general environmental benefit.[45] The hydrogen industry's proposal to market any hydrogen derived from biogenic feedstocks as "green" would violate Federal Trade Commission guidance for avoiding deceptive marketing claims because the industry could not show that such products generate only positive environmental impacts. Just the opposite—purchasing biomethane and biomass to create hydrogen could impose severe environmental harms, including increased carbon intensity compared to fossil-based alternatives. Because reasonable customers would not expect "green"

[40] Leadership Counsel for Justice and Accountability, A Working Paper on the CDFA Dairy Digester Research and Development Program (Apr. 2019), https://leadershipcounsel.org/wp-content/uploads/2019/04/A-Working-Paper-onGGRF-Dairy-Digester-Program.pdf.
[41] Lisa Fischer, Renewable and Decarbonized Gas – Options for a Zero Emissions Society, at 12 (June 2018), https://www.e3g.org/wpcontent/uploads/E3G_Renewable_and_decarbonised_gas_Options_for_a_zero-emissions_society.pdf.
[42] Cal. Bus. & Prof. Code § 17580.5(a).
[43] 16 C.F.R. § 260.4(b).
[44] *Id.*
[45] Indeed, the strategy of marketing hydrogen as "green" is very similar to the first example the Federal Trade Commission provides for a deceptive claim of general environmental benefit: "The brand name 'Eco-friendly' likely conveys that the product has far-reaching environmental benefits and may convey that the product has no negative environmental impact. Because it is highly unlikely that the marketer can substantiate these claims, the use of such a brand name is deceptive." § 260.4(d).

products to cause environmental damage, the Commission should not allow gas utilities to deceptively market hydrogen from all biogenic sources as "green."

For instance, some customers who purchase hydrogen marketed as "green" would likely be surprised and dismayed to learn that the hydrogen is the product of manure lagoons at CAFOs. A significant portion of the biomethane that is currently sold in California comes from these industrial agriculture facilities, which cause significant harm to neighboring communities that are already overburdened by pollution.[46] Dairy CAFOs are the largest source of ozone-forming pollution in the Southern San Joaquin Valley, an area currently in extreme nonattainment with federal 8-hour ozone standards.[47] VOCs from dairy feed alone cause roughly twice the ozone in the region as passenger cars, the next largest source of VOCs.[48] Nitrogen runoff from these facilities also pollutes local drinking water supplies, groundwater, and waterways.[49] However, as discussed above, policies that create a market for biomethane inadvertently drive increases in this health-harming pollution.[50] Incentives for manure lagoons and the associated pollution at industrial agricultural facilities are the antithesis of what reasonable consumers would expect from a purportedly "green" product.

Deriving hydrogen from biomass also has the potential to cause environmental harms that are incompatible with reasonable expectations for a "green" product. Under the hydrogen industry's preferred approach, the Commission would label hydrogen from any biomass feedstock—even biomass from logged forests—as "green." However, cutting down forests for biomass energy harms forest ecosystems. Extracting biomass from California forests reduces their ability to store and sequester carbon, removes essential habitat features that support forest

[46] See generally Leadership Counsel, A Working Paper on the CDFA Dairy Digester Research and Development Program (Apr. 3, 2019), https://leadershipcounsel.org/wp-content/uploads/2019/04/A-Working-Paper-on-GGRF-Dairy-Digester-Program.pdf.
[47] Sheraz Gill et al., Air Pollution Control Officer's Revision of the Dairy VOC Emission Factors, SJVAPCD, at 9 (Feb. 2012), https://www.valleyair.org/busind/pto/emission_factors/2012-Final-Dairy-EE-Report/FinalDairyEFReport(2-23-12).pdf; U.S. E.P.A. Greenbook, available at https://www3.epa.gov/airquality/greenbook/anayo_ca.html.
[48] Howard, Cody, et al, Reactive Organic Gas Emissions from Livestock Feed Contribute Significantly to Ozone Production in Central California, Enciron. Sci. Technical, 44, 2309-2314.
[49] Eli Moore et al., The Human Costs of Nitrate-contaminated Drinking Water in the San Joaquin Valley, Pacific Institute, at 7 (Mar. 2011), https://pacinst.org/wp-content/uploads/2011/03/nitrate_contamination3.pdf; *see also* J.P. Cativiela et al., Summary Representative Monitoring Report (Revised*), CVDRMP, at 6 (Apr. 19, 2019) (groundwater nitrate contamination beneath all 42 dairies, with the most severe contamination beneath manure land application areas), https://www.waterboards.ca.gov/centralvalley/water_issues/confined_animal_facilities/groundwater_monitoring/srmr_20190419.pdf.
[50] Discussion Section II.C., above.

biodiversity, and hinders nutrient cycling.[51] It would be deceptive to market hydrogen produced from logging California forests as "green" because customers would not expect that the production of supposedly green hydrogen caused the degradation of wildlife habitat and the net loss of carbon storage.

These are just two examples of how the hydrogen industry's definition of green hydrogen could mislead customers. The Commission should avoid confusing customers about the gases included in the Standard Renewable Gas Interconnection Tariff by only allowing the utilities to include hydrogen produced through the electrolysis of renewable energy for which the producers retire the renewable energy credits.

III. Given the Narrow Record and the Complexity of the Hydrogen Production Pathways, the Commission Should Adopt a Narrow Definition Now and Only Consider Expanding It When Evidence Supports Such an Expansion.

There is no benefit to the Commission rushing and imprudently declaring environmentally deleterious hydrogen production pathways to be eligible for the Standard Renewable Gas Interconnection tariff, especially when the Commission is many years away from being able to set standards and protocols for hydrogen injection.

Conducting the research necessary to support hydrogen injection standards and protocols will be a lengthy process.[52] As the Joint Gas Utilities note, they have proposed an "initial" research program that they hope "will help inform and guide future large-scale demonstration projects."[53] The California Energy Commission ("CEC") also intends to contract for several research projects related to the production and use of renewable hydrogen. Most relevant to the question of what sources of renewable hydrogen may become available, the CEC will fund research on the efficiency, cost, and environmental benefits of emerging technologies for hydrogen production.[54] The CEC also intends to fund research on some of the same safety issues that the Joint Gas Utilities propose to explore in their proposed pilot, which will provide

[51] Center for Biological Diversity, Forest Biomass Energy is a False Solution at pdf p. 11, https://www.biologicaldiversity.org/programs/climate_law_institute/pdfs/Forest-Bioenergy-Briefing-Book.pdf.
[52] Safety, reliability, and public health consequences that would require further research to make hydrogen injection possible are discussed below in Discussion Section V.
[53] Joint Gas Utility Comments at 4.
[54] CEC Staff Report, Natural Gas Research and Development Program Proposed Budget Plan for Fiscal Year 2020-21 (approved in CPUC Resolution G-3571, Nov. 5, 2020) at 41, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K789/350789679.PDF.

an important independent check on the gas utilities' results.[55] The Commission has approved this spending in the CEC's most recent proposed Natural Gas Research and Development Program budget, for which the agency would need to award contracts by the end of June 2022. It is unclear how many more years it will take the researchers to conduct their analysis after the contract award.

California is also many years away from having a sufficient supply of electrolytic hydrogen to satisfy the demand for renewable hydrogen from sectors that are higher priority than the gas pipeline network. As stated above, the vast majority (>95%) of hydrogen globally is produced with fossil fuels, with less than .1% percent of global production coming from water electrolysis.[56] Only a fraction of that hydrogen is powered by dedicated renewables—a production pathway that stands at a technology readiness level ranging between "demonstration" and "early adoption."[57] There is no expectation that commercial production of synthetic fuels like renewable hydrogen will occur in the 2020s.[58] Multiple independent researchers agree it will be about 10 to 15 years until power-to-gas is profitable, even assuming improved technology and altered regulatory frameworks.[59] Bloomberg New Energy Finance and Wood Mackenzie issued reports in 2020 stating that green hydrogen (defined as hydrogen produced using renewable electricity to split water in an electrolyzer) *could* become cost-competitive with fossil-derived "grey" hydrogen by 2030 as economies of scale drive down the cost of electrolyzers and the price of wind and solar power continues to fall.[60] It will be several years, preconditioned on a massive build out of electrolyzers and dedicated renewable generation, before appreciable volumes of renewable hydrogen will become available.

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[55] *Id.* at 36-37 (discussing research on safety impacts of hydrogen in end-use appliances), 46-48 (discussing pilot test and demonstration of hydrogen blending into existing California natural gas pipelines).

[56] International Energy Agency, *The Future of Hydrogen* (June 2019), https://www.iea.org/reports/the-future-of-hydrogen.

[57] EsadeGeo, Technologies of the Energy Transition: Low and Zero-Carbon Hydrogen (Dec. 16, 2020) https://dobetter.esade.edu/en/low-zero-carbon-hydrogen?_wrapper_format=html

[58] Transport & Environment, *Why Adding Fuel Credits to Vehicle Standards is a Bad Idea*, at 2 (Nov. 2020) https://www.transportenvironment.org/sites/te/files/publications/2020_11_TE_rebuttal_Why_adding_fuel_credits_vehicle_standards_is_bad_idea.pdf.

[59] Staffel *et al.*, The Role of Hydrogen and Fuel Cells in the Global Energy System, supra note 16.

[60] BloombergNEF, *Hydrogen Economy Outlook* (Mar. 2020), https://assets.bbhub.io/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf; Wood MacKenzie, Hydrogen Landscape 2020, https://www.woodmac.com/our-expertise/focus/transition/2020-hydrogen-landscape/.

Even when renewable hydrogen production does ramp up, it will urgently be needed for harder-to-abate sectors such as industries that depend on hydrogen as a production input. Just meeting current hydrogen demand with renewable electrolytic hydrogen would require 3,600 TWh of renewable electricity—more than the European Union's total annual electricity generation.[61] The colossal task of replacing existing fossil hydrogen use with renewable hydrogen should be prioritized over displacing fossil gas demand that can be avoided through electrification. Renewable hydrogen will *always* be more expensive and energy intensive than direct use of renewable electricity wherever it is feasible to use, so it should be reserved for harder-to-abate sectors. Researchers have found that limiting renewable hydrogen demand to only essential sectors helps mitigate economy wide costs,[62] and have called for "reduc[ing] the risk of oversizing by focusing on indispensable demand."[63] It is therefore crucial that the Commission resist efforts by gas utilities to create new categories of hydrogen demand that commandeer an expensive resource to extend the life of the gas system or justify its expansion.

IV. The Commission Should Reject the Joint Gas Utilities' Request to Inject Hydrogen that Does Not Reduce Dependence on Fossil Fuels.

The Joint Gas Utilities ask the Commission to separate its determination regarding the definition of renewable hydrogen from its determination regarding what hydrogen is eligible for pipeline injection "so that hydrogen generated from all feedstocks would be eligible for pipeline injection so long as all injection standards are met."[64] The Commission should forcefully reject requests for permission to inject hydrogen from all production pathways—including carbon-intensive reformation of fossil gas—into the gas pipeline network.

As a preliminary matter, the injection of non-renewable hydrogen is an issue that is outside the scope of this proceeding. Commissioner Rechtschaffen expanded the scope of this proceeding to consider the standards for injecting only renewable hydrogen.[65] This proceeding

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[61] International Energy Agency, *The Future of Hydrogen*, supra note 56.
[62] Aurora, Hydrogen in the NW European Energy System, (Aug. 31, 2020) at 5 https://www.auroraer.com/wp-content/uploads/2020/08/Aurora-Hydrogen-in-the-Northwest-European-energy-system.pdf.
[63] Agora Energiewende, No Regret Hydrogen (Feb. 2021) https://static.agora-energiewende.de/fileadmin2/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf.
[64] Joint Gas Utility Comments at 2.
[65] November 2019 scoping memo at 7 ("the new phase of this proceeding will establish injection standards and interconnection protocols for renewable hydrogen connecting to the natural gas pipeline system to ensure safety and integrity of the gas delivery system and compatibility with end-uses"), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K307/320307147.PDF.

is solely considering renewable hydrogen because Commissioner Rechtschaffen decided to give the utilities an opportunity to show that renewable hydrogen could "offset the use of fossil fuels" and "reduce the carbon intensity of the gas used in the state."[66] Allowing the Joint Gas Utilities to inject hydrogen regardless of its feedstock would not advance these goals.

Non-renewable hydrogen is not just outside the scope of this proceeding—it could reverse California's climate progress by increasing the carbon-intensity of pipeline gas. According to the estimates in the Lookup Tables CARB developed for the LCFS program, compressed gas from pipeline average fossil gas in North America has a carbon intensity of about 79 grams of CO2e/MJ.[67] The estimate for compressed hydrogen from steam reformation of North American fossil gas is even greater: about 118 grams of CO2e/MJ.[68] The energy-intensive process of steam methane reformation is currently the standard method for producing hydrogen in the United States.[69] As a recent CEC staff report stated, "steam methane reforming produces GHG emissions that do not align with the decarbonization goals of California."[70]

Indeed, California should strive to eliminate reliance on non-renewable hydrogen where it is already in use because it is a significant source of greenhouse gas emissions. Currently, more than 95% of hydrogen produced globally, is produced from fossil fuels, making hydrogen's carbon footprint equal to those of the U.K. and Indonesia combined.[71] Rather than creating new opportunities for non-renewable hydrogen, California's leaders should ensure that industry transitions away from it as swiftly as possible.

V. Before Considering Pipeline Injection, the Commission Must Address Critical Issues Related to Safety, Ratepayer Protections, and Public Health, and Set Clear Limits to Ensure Hydrogen Use Does Not Perpetuate Reliance on Fossil Gas or Increase Harmful Emissions.

Sierra Club and Food & Water Watch appreciate the Joint Gas Utilities' recognition that they cannot propose standards or protocols for hydrogen injection based on currently available

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[66] *Id.* at 1, 6.
[67] CARB, Lookup Table for Gasoline and Diesel and Fuels that Substitute for Gasoline and Diesel, supra.
[68] *Id.*
[69] U.S. Department of Energy, Hydrogen Production and Distribution (Accessed Mar. 3, 2021) https://afdc.energy.gov/fuels/hydrogen_production.html#:~:text=The%20major%20hydrogen%2Dproducing%20states,producing%20fertilizer%2C%20and%20processing%20foods.
[70] CEC Staff Report, Natural Gas Research and Development Program Proposed Budget Plan for Fiscal Year 2020-21 at 41, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K789/350789679.PDF.
[71] International Energy Agency, *The Future of Hydrogen*, supra note 56.

information.[72] Even if the Commission approves the research project that the Joint Gas Utilities have proposed in lieu of complying with Commissioner Rechtschaffen's instructions to propose standards and protocols, it is not likely that the Commission will have sufficient information to allow pipeline injection of hydrogen. Before even considering pipeline injection, the Commission should articulate clear limits on hydrogen use related to safety, climate, and health and thoroughly investigate safety and reliability, whether costly upgrades would be necessary, and the potential for increased emissions.

A. The Commission should not allow pipeline injection of hydrogen unless there is compelling evidence that doing so would not impede safety and reliability.

The Joint Gas Utilities' application for a hydrogen blending demonstration project highlights numerous potential risks to safety and reliability from injecting hydrogen into the gas pipeline network. For instance, the elastomers and rubbers that seal many pipeline components can swell or develop voids after exposure to pure hydrogen; hydrogen can cause embrittlement of steel pipes; and the utilities do not know how much hydrogen they can safely store in the underground formations that they rely on for gas storage.[73] These are just a few examples of the threats the Commission would need to assess before allowing utilities to inject hydrogen into the gas distribution system.

B. To protect ratepayers from unreasonable costs, the Commission should not allow pipeline injection of hydrogen if new investments in the gas distribution system would be required to ensure safety and reliability.

It is imperative to avoid unreasonable investments in the gas distribution system because any new costs are likely to become stranded assets. As California takes advantage of opportunities to decarbonize buildings with technologies that are already available, customers will disconnect from the gas system and leave fewer customers to shoulder the costs of this behemoth.[74] The first step in controlling the looming stranded asset crisis in the gas industry is to stop adding more assets to the system. The Commission should not invest any resources to enable the gas distribution network to carry hydrogen before first seeking more cost-effective

[72] Joint Gas Utilities Comments at 2.
[73] A.20-11-004, Application Chapter 4, page 8, lines 2-4; *id.* at page 9, 19-25; *id.* at 11, lines 10-12.
[74] Gridworks, California's Gas System in Transition – Equitable, Affordable, Decarbonized and Smaller (Sept. 2019) https://gridworks.org/initiatives/cagas-system-transition/.

and equitable decarbonization investments, like helping low-income customers access non-polluting appliances.

The Commission must not operate under the false assumption that hardening the gas pipeline system to carry hydrogen will allow it to continue to operate at its current scale in a carbon-constrained world. Even after injecting the maximum feasible amount of hydrogen, there is simply not enough biomethane or so-called "renewable gas" to fill the remainder of the pipeline network. Renewable electrolytic hydrogen could theoretically help supplement biomethane in pipeline gas to incrementally reduce the carbon intensity of pipeline gas. One widely held view is that "most parts of the natural gas system can tolerate mixtures up to 10% by volume hydrogen," provided that regulators "independently verify estimates to ensure compatibility of existing components and materials to hydrogen blends and to verify repairs to ensure that transmission and distribution lines would be safe for hydrogen exposure."[75] Even optimistic scenarios estimate that the pipeline system could only handle up to 20% hydrogen by volume – equal to just 7% of the energy in the gas pipeline system.[76] In that case, fully decarbonizing the gas system would require the gas utilities to procure enough renewable methane to supply the remaining 93% of energy on the system. As discussed above, biomethane can likely only displace about 3% of California's current gas use and other sources of "renewable" gas are decades away.[77] While renewable hydrogen provides a potential pathway to fully decarbonize sectors that require streams of pure hydrogen, it is a dead end for decarbonizing the vast gas system.

It would be wasteful to pour resources into upgrading the gas distribution network to tolerate hydrogen when there are readily available, lower-cost alternatives. California-specific research shows that injecting renewable hydrogen into the gas distribution grid is likely one of the least cost-effective options for reducing emissions from the appliances that currently rely on the gas distribution network for fuel. The California Energy Commission's 2018 landmark analysis projected that California would only inject renewable hydrogen into the gas pipeline system in the most expensive decarbonization pathway considered, called "No Building

[75] Amy Myers Jaffe *et al.*, *The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology*, at 69 (Mar. 2017), https://escholarship.org/content/qt2tp3n5pm/qt2tp3n5pm_noSplash_9284d90efb2dcd62f220c81da1f89b58.pdf?t=pszeud.
[76] Staffel *et al.*, The Role of Hydrogen and Fuel Cells in the Global Energy System, supra note 16, at 479.
[77] Discussion Section III.

Electrification with Power-to-Gas."[78] The researchers estimated that relying on hydrogen and synthetic methane to decarbonize the gas distribution network would remain among the most costly decarbonization strategies in 2050.[79] A more recent PG&E-funded study found that California could save $20 billion by choosing a high electrification pathway instead of relying on renewable gases like hydrogen and synthetic methane in buildings.[80] The Commission should direct scarce resources to the most cost-effective decarbonization pathways.

For these reasons, the Commission should articulate now that it will not allow any upgrades that will further perpetuate dependence on a pipeline system based on fossil gas. If upgrades are needed, the Commission should refuse ratepayer recovery of such investments to protect customers from paying for stranded gas system assets.

C. The Commission should not allow pipeline injection of hydrogen unless it first determines that hydrogen would not increase emissions from any equipment that burns gas.

Adding hydrogen to pipeline gas threatens to increase NOx emissions at end-uses. As the Joint Gas Utilities acknowledge in the testimony supporting the application for their research project, "[a] hydrogen-natural gas blend may yield higher NOx emissions than natural gas because hydrogen burns faster than natural gas, which increases combustion temperatures and reduces ignition lag."[81] NOx pollution contributes to smog formation, which puts Californians at risk for asthma, cardiovascular disease, and other illnesses.[82] Any increases in NOx emissions are unacceptable because many Californians already breathe some of the most smog-choked air in the country.[83] Increases in emissions from household appliances could be especially

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[78] California Energy Commission, Deep Decarbonization in a High Renewables Future (June 2018), Figure 27, Tables A-1 and A-2, https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf.
[79] *Id.* at A-7 (estimating that transitioning to 7% pipeline hydrogen and 25% pipeline synthetic methane would cost $1100 per ton CO2-equivalent; only one potential measure was higher cost).
[80] Gridworks, California's Gas System in Transition (Sept. 2019), at 8 (finding that "[e]ven in an 'optimistic' scenario that assumed aggressively lower-cost hydrogen and [synthetic gas] in the future, the high electrification scenario would still cost $6 billion less per year" than the high electrification scenario"), https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.
[81] A.20-11-004, Application Chapter 4, page 17, lines 12-14.
[82] CARB, Nitrogen Dioxide & Health https://ww2.arb.ca.gov/resources/nitrogen-dioxide-and-health
[83] California cities make up 8 of the top 10, and each of the top 5, most polluted cities for ozone (which NOx is a precursor to).
American Lung Association, State of the Air Report (2020) https://www.stateoftheair.org/city-rankings/most-polluted-cities.html.

detrimental because gas-burning appliances pollute the indoor air in homes, where children, seniors, and other vulnerable residents suffer exposure.[84]

It is unclear when there will be sufficient data for the Commission to assess the air quality and public health impacts of blending hydrogen into the gas pipeline network. A 2020 U.S. Department of Energy report found a need for further research and development on hydrogen combustion to "Improve understanding of combustion behavior and optimization of component designs for low NOx combustion."[85] In their application, the Joint Gas Utilities note there is a knowledge gap regarding the emissions impacts on gas end-user equipment and discuss research that SoCalGas is already funding on emissions impacts to residential and commercial appliances.[86] Regardless of the conclusions of these gas industry-funded studies, the Commission will need independent research to understand the emissions impacts of hydrogen blending. In addition to gathering independent research on the emissions impacts on household and commercial appliances, the Commission must ensure hydrogen blending will not increase emissions from other equipment that burns gas, including electric generators and vehicles. The Joint Gas Utilities acknowledge that further research and technological advancements are necessary to control emissions from gas turbines burning gas with a higher hydrogen content.[87] However, their application sheds no light on when those advancements might occur or if they would require unreasonable and potentially stranded investments in fossil generators.

These emissions risks are present in any use of hydrogen that requires combustion, whereas current technology provides opportunities to use renewable hydrogen in fuel cells without threatening ambient air quality. The Commission must make clear now that it will not allow any hydrogen use that increases such emissions and only proceed to considering pipeline injection if it is clearly demonstrated that no increases will occur. Foregoing the injection of renewable hydrogen into the gas system to avoid these dangerous consequences would allow California to reserve its limited supply of renewable hydrogen to displace the fossil-derived hydrogen currently used in industry and fuel cells.

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[84] Yifang Zhu *et al.*, Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California (Apr. 2020) https://ucla.app.box.com/s/xyzt8jc1ixnetiv0269qe704wu0ihif7.
[85] U.S. Department of Energy, Hydrogen Program Plan, at 24 (2020), https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf#page=28.
[86] A.20-11-004, Application Chapter 4, page 17, lines 18-26.
[87] *Id.* at 29, lines 3-22.

CONCLUSION

If the Commission adopts a definition of renewable hydrogen at this time, it should only include renewable electrolytic hydrogen. The Joint Gas Utilities' and hydrogen industry's preferred definitions are misguided and would include carbon-intensive and environmentally damaging hydrogen production pathways.

To avoid any unintended consequences of injecting hydrogen into the gas pipeline network, the Commission should adopt principles to govern any future deliberation on hydrogen blending. First, the Commission should reject the Joint Gas Utilities' suggestion that they should be allowed to inject non-renewable hydrogen into the gas system. Second, the Commission should clarify that it will not allow pipeline injection of hydrogen unless there is compelling evidence that doing so would not impede safety and reliability. Third, the Commission should not allow hydrogen injection into the pipeline if it would require the utilities to rate base new investments in upgraded infrastructure. Fourth, the Commission should not allow utilities to inject hydrogen into the gas pipeline network if doing so would risk increasing health-harming air pollution from the equipment that burns the gas. While the Commission, CEC, and utilities continue to study these essential questions, the Commission must aggressively take advantage of technology that is already available today—particularly, electric appliances—to reduce emissions from the end-uses that currently rely on the gas distribution system.

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Respectfully submitted,

/s/ Sara Gersen
Sara Gersen
Email: sgersen@earthjustice.org
Earthjustice
50 California Street, Suite 500
San Francisco, CA 94111
(415) 217-2000

Representing Sierra Club

/s/ Tyler Lobdell
Tyler Lobdell
Email: tlobdell@fwwatch.org
Food & Water Watch
1616 P St. NW, #300
Washington, DC 20036
(208) 209-3569

Representing Food & Water Watch